Directive appearing in the Federal Register for Wednesday, November 8, 1978. (43 FR 52122).

Jerome Kurtz,

Commissioner.

[FR Doc. 79-28123 Filed 9-7-79; 8:45 am]

BILLING CODE 4830-01-M

Office of the Secretary

Foreign Portfolio Investment Survey Advisory Committee; Meeting

Pursuant to the Federal Advisory Committee Act, Pub. L. 92-463, notice is hereby given that the initial meeting of the Foreign Portfolio Investment Survey Advisory committee will be held on September 27, 1979 starting at 10:00 A.M. in Room 4121 of the Main Treasury Building, 15th Street and Pennsylvania Avenue, NW., Washington, D.C.

This Committee has been created to provide the Secretary with views from qualified persons representing business, organized labor, and the academic community regarding the collection of statistics on portfolio investment by foreigners in the United States and on U.S. residents portfolio investment abroad as mandated by the International Investment Survey Act of 1976, Pub. L. 94-472.

The Committee will consider the results of a feasibility study of alternative approaches to surveying U.S. residents' portfolio investment abroad. The International Investment Survey Act requires that a balance between costs, burden to the public, and the need for information must be fully considered before implementing any data collection program. In this regard, the views and recommendations of the Committee have been solicited.

The meeting will be open to the public. A limited number of seats will be available on a first come, first serve basis. In order to facilitate admittance, persons interested in attending are asked to call (202) 566-2757 before September 24, 1979.

Interested persons may file a written statement with the Committee before, during or within one week after the meeting. [The Chairman may, as time permits, entertain oral comments from members of the public attending the meeting. Persons interested in making oral statements are asked to so indicate in advance of the meeting.]

Inquiries may be directed to: Mr. George C. Miller, Jr., Executive Assistant, Office of the Assistant Secretary (Economic Policy), U.S. Department of the Treasury, Washington, D.C. 20220.

[Minutes of the meeting will be available from the above office.]

Daniel H. Brill,

Assistant Secretary, Economic Policy.

September 5, 1979.

[FR Doc. 79-28092 Filed 9-7-79; 8:45 am]

BILLING CODE 4810-25-M

INTERSTATE COMMERCE COMMISSION

Agricultural Cooperatives; Notice to the Commission of Intent To Perform Interstate Transportation for Certain Nonmembers

Dated: September 5, 1979.

The following Notices were filed in accordance with section 10526(a)(5) of the Interstate Commerce Act. These rules provide that agricultural cooperatives intending to perform nonmember, nonexempt, interstate transportation must file the Notice, Form BOP 102, with the Commission within 30 days of its annual meetings each year. Any subsequent change concerning officers, directors, and location of transportation records shall require the filing of a supplemental Notice within 30 days of such change. The name and address of the agricultural cooperative, the location of the records, and the name and address of the person to whom inquiries and correspondence should be addressed, are published here for interested persons. Submission of information that could have bearing upon the propriety of a filing should be directed to the Commission's Bureau of Investigations and Enforcement, Washington, D.C. 20423. The Notices are in a central file, and can be examined at the Office of the Secretary, Interstate Commerce Commission, Washington, D.C.

(1) Special Freight Systems, Inc. (Complete Legal Name Of Cooperative Association Or Federation Of Cooperative Associations), P.O. Box 366—Hwy. 17 South, Wauchula, FL 33873.

Principal Mailing Address (Street No., City, State, and Zip Code): P.O. Box 166—Mt. Royal Plaza, Paulsboro, NJ 08066.

Where Are Records Of Your Motor Transportation Maintained (Street No., City, State and Zip Code): Daniel Latta & Sons, Inc., Mt. Royal Plaza, Paulsboro, NJ 08066 (Person To Whom Inquiries And Correspondence Should Be Addressed (Name and Mailing Address)).

(2) International Farmers Union, Inc. (Complete Legal Name Of Cooperative Association Or Federation Of Cooperative Associations), Ingenieros 430, Nogales, Sonora, Mexico.

Principal Mailing Address (Street No., City, State, and Zip Code): Ingenieros 430, Nogales, Sonora, Mexico.

Where Are Records Of Your Motor Transportation Maintained (Street No., City, State and Zip Code): Alfonso Cuevas, Apdo. Postal No. 329, Nogales, Mexico. (Person To Whom Inquiries And Correspondence Should Be Addressed (Name and Mailing Address)).

(3) Sinaloa Growers and Producers, Inc. (Complete Legal Name Of Cooperative Association Or Federation Of Cooperative Associations), Apartado Postal No. 1-133, Mexicali, Baja California, Mexico.

Prinicipal Mailing Address (Street No., City, State, and Zip Code): 292 Naranjos St., Los Pinos, Mexicali, B.C., Mexico.

Where Are Records Of Your Motor Transportation Maintained (Street No., City, State and Zip Code): Manuel Balenzuela A., Apartado Postal No. 1-133, Mexicali, B.C., Mexico (Person To Whom Inquiries And Correspondence Should Be Addressed (Name and Mailing Address)).

(4) World Growers Alliance, Inc. (Complete Legal Name Of Cooperative Association Or Federation Of Cooperative Associations), 292 Naranjos St., Los Pinos, Mexicali B.C.

Principal Mailing Address (Street No., City, State, and Zip Code): Refugio Rodriguez, 292 Naranjos St., Los Pinos, B.C. Mexico.

Where Are Records Of Your Motor Transportation Maintained (Street No., City, State and Zip Code): Refugio Rodriguez, 292 Naranjos, Los Pinos B.C., Mexico (Person To Whom Inquiries And Correspondence Should Be Addressed (Name and Mailing Address)).

(5) Great American Trucking Inc. (Complete Legal Name Of Cooperative Association Or Federation Of Cooperative Associations), P.O. Box 596, La Habra, CA 90631.

Principal Mailing Address (Street No., City, State, and Zip Code): 1624 E. Holt Ave., Ontario, CA 91761.

Where Are Records Of Your Motor Transportation Maintained (Street No., City, State and Zip Code): Jim Brodie, Box 244, San Juan, TX. (Person To Whom Inquiries And Correspondence Should Be Addressed (Name and Mailing Address)).

Agatha L. Mergenovich,

Secretary.

[FR Doc. 79-28096 Filed 9-7-79; 8:45 am]

BILLING CODE 7035-01-M

Fourth Section Application for Relief

September 5, 1979.

This application for long-and-short-haul relief has been filed with the I.C.C.

Protests are due at the I.C.C. on or before September 25, 1979.

FSA No. 43741, Southwestern Freight Bureau, Agent's No. B-22, carload rates on sugar, beet or cane, in bulk, in covered hoppers, from stations in Colorado, Idaho, Nebraska, Utah and Wyoming, to Dallas and Ft. Worth, Tex. Also, returned shipments in the reverse direction. Rates are published in Sup. 17 to its Tariff ICC SWFB 4412, to become effective September 25, 1979. Ground for relief—market competition.

By the Commission.

Agatha L. Mergenovich,

Secretary.

[FR Doc. 79-28095 Filed 9-7-79; 8:45 am]

BILLING CODE 7035-01-M

[Notice Finance Docket No. 29121]

Railroad Car Service Pooling Application; Notice of Filing and Proposed Special Rules of Procedure

September 5, 1979.

An application, as summarized below, termed a "Railgon Pooling Application," has been filed by certain common carriers by railroad, the trustees of certain common carriers by railroad, Railgon Company and Trailer Train Company under section 11342 of Title 49, U.S. Code "Transportation" (a) for authority to enter into an agreement for the pooling of car service with respect to gondola cars and the pooling and division of earnings as affected thereby and (b) for approval of said agreement. Thr railroads listed as applicants are:

The Atchison, Topeka and Santa Fe Railway Company; The Baltimore and Ohio Railroad Company; Robert W. Meserve and Benjamin H. Lacy, Trustees of Boston and Maine Corporation, Debtor; Burlington Northern Inc.; Central of Georgia Railroad Company; The Chesapeake and Ohio Railway Company; Chicago and North Western Transportation Company; Richard B. Ogilvie, Trustee of the Property of Chicago, Milwaukee, St. Paul and Pacific Railroad Company, Debtor; William M. Gibbons, Trustee of the Property of Chicago, Rock Island and Pacific Railroad Company, Debtor; Consolidated Rail Corporation; The Denver and Rio Grande Western Railroad Company; Detroit, Toledo & Ironton Railroad, Company; Florida East Coast Railway Company; Illinois Central Gulf Railroad Company; The Kansas City Southern Railway Company; Louisville and Nashville Railroad Company; Missouri-Kansas-Texas Railroad Company; Missouri Pacific Railroad Company; Richmond, Fredericksburg and Potomac Railroad Company; St. Louis-San Francisco Railway Company; St. Louis Southwestern Railway Company; Seaboard Coast Line Railroad Company; Southern Pacific Transportation Company; Southern Railway Company; Toledo, Peoria & Western Railroad Company; Union Pacific Railroad Company; Western Maryland Railway Company; The Western Pacific Railroad Company.

The application and an appended "Railgon Pooling Agreement" propose the joint ownership and management of a pool of gondola cars through Railgon Company, a subsidiary of Trailer Train Company. The latter, principally owned by the Railroad Applicants, is now engaged in a similar activity with respect to flat cars and, through a wholly-owned subsidiary, Railbox Company, with respect to box cars. Under the plan proposed, the Railroad Applicants will agree with each other to act through Railgon Company (a) to pool experience and research and to design and develop standardized types of gondola cars for maximum utilization; (b) to pool information as to equipment needs to secure an evaluation of total needs; (c) jointly to purchase needed equipment so as to achieve early and consistent deliveries and economies which result in low unit costs; (d) to act together to secure favorable equipment financing terms; (e) to pool various aspects of utilization, maintenance and accounting; and (f) to pool the ownership costs and expenses of operation and to provide an equitable sharing of costs and expenses associated with the pooling plan. Applicants state that the gondola cars will be free-running cars, available for loading as needed, and not subject to car service rules and regulations normally applicable to railroad-owned gondola cars.

Participation in the pool will not be limited to the railroads which have joined in the filing of the application, but will be open to all other United States carriers of property by railroad who become signatories to the "Railgon Pooling Agreement" and comply with its provisions. Applicants have requested that the approving order in this proceeding provide a period of 180 days following the date thereof during which other railroads may join the pooling plan by filing with the Commission a request to that effect.

A copy of the application is on file, and can be examined in the Office of the Secretary, Interstate Commerce Commission, Washington, D.C. In addition, applicants have offered to mail each interested party a copy of the application upon receiving a request therefor addressed to:

Mr. Robert J. Williams, Vice President, General Counsel, and Secretary, Trailer Train Company, 300 South Wacker Drive, Chicago, Illinois 60606.

Any person desiring to participate in the proceedings with respect to the application may file a pleading, stating the nature of its interest and its position with respect thereto, on or before October 10, 1979, with copies to applicants' counsel, Mr. Robert J. Williams, at the address stated above, and to Mr. Paul R. Duke, Covington & Burling, 888 Sixteenth Street, N.W., Washington, D.C. 20006.

In the opinion of applicants, the requested Commission action will not constitute major regulatory action within the meaning of the Energy Policy and Conservation Act of 1975 (42 U.S.C. 6201 *et seq.*) and the Commission's regulations thereunder (49 CFR 1106.1 *et seq.*). Any protest may include a statement indicating the presence or absence of any impact of the requested Commission action on energy conservation and energy efficiency. If such impact is alleged, the statement shall be accompanied by supporting data indicating the nature and degree of the anticipated energy impact.

Under the Commission's regulations (49 CFR 1108.10), the proposal is not a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969. In the opinion of applicants, the requested Commission action will not significantly affect the quality of the human environment within the meaning of said Act. Any protest may include a statement indicating the presence or absence of environmental impacts. If any such effect is alleged to be present, the statement shall include the data required by the Commission's regulations (49 CFR 1108.12(e)).

The Commission has adopted the following Special Rules of Procedure for this proceeding:

1. The hearings in these matters will be conducted under modified procedure in accordance with the following provisions:

(a) Applicants' verified statements will be due ten days after the expiration of the date upon which notices of intention to participate in the proceeding shall be due;

(b) Verified statements by all other parties shall be due 20 days thereafter;

(c) Verified reply statements by all parties shall be due ten days thereafter; and

(d) No oral hearing is comtemplated.

2. If the application is approved, a period of 180 days following the effective date of the Commission's order shall be provided during which other carriers of property by railroad shall be authorized to join the pooling agreement.

Any protests submitted shall be filed with the Commission no later than October 10, 1979.

By the Commission.

Agatha L. Mergenovich,

Secretary.

[FR Doc. 79-28094 Filed 9-7-79; 8:45 am]

BILLING CODE 7035-01-M

Sunshine Act Meetings

Federal Register

Vol. 44, No. 176

Monday, September 10, 1979

This section of the FEDERAL REGISTER contains notices of meetings published under the "Government in the Sunshine Act" (Pub. L. 94-409) 5 U.S.C. 552b(e)(3).

CONTENTS

1

[M-241, Amdt. 1; Sept. 5, 1979]

CIVIL AERONAUTICS BOARD.

Notice of addition of item to the September 6, 1979, meeting.

TIME AND DATE: 10 a.m., September 6, 1979.

PLACE: Room 1027, 1825 Connecticut Avenue NW., Washington, D.C 20428.

SUBJECT: 2a. Docket 33019, Chicago-Midway Expanded Service Investigation (Memo 7909-M, OGC).

STATUS: Open.

PERSON TO CONTACT: Phyllis T. Kaylor, the Secretary, (202) 673-5068.

SUPPLEMENTARY INFORMATION: This item was inadvertently omitted from the September 6, 1979 agenda. Accordingly, the following Members have voted that agency business requires that this item be added to the September 6, 1979 agenda and that no earlier announcement of this addition was possible.

Chairman Marvin S. Cohen
Member Richard J. O'Melia
Member Elizabeth E. Bailey
Member Gloria Schaffer

[S-1746-79 Filed 9-6-79; 3:08 pm]

BILLING CODE 6320-01-M

2

EQUAL EMPLOYMENT OPPORTUNITY COMMISSION.

TIME AND DATE: 9:30 a.m. (Eastern Time), Tuesday, September 11, 1979.

PLACE: Commission Conference Room, No. 5240, on the fifth floor of the Columbia Plaza Office Building, 2401 E Street N.W., Washington, DC. 20506.

MATTERS TO BE CONSIDERED:

Open to the Public

(1) Proposed 706 Agency Designation for the City of Detroit Human Rights Department.

(2) Final 706 designation of three State and Local Agencies.

(3) Proposed Questionnaire requesting information on the impact of Federal equal employment opportunity programs and activities, to be sent to employers.

(4) Report on Commission operations by Executive Director.

Closed to the Public

(1) Litigation Authorization: General Counsel Recommendations.

Note.—Any matter not discussed or concluded may be carried over to a later meeting.

CONTACT PERSON FOR MORE INFORMATION: Marie D. Wilson, Executive Officer, Executive Secretariat, at (202) 634-6748.

This Notice Issued September 4, 1979.

[S-1749-79 Filed 9-6-79; 4:02 pm]

BILLING CODE 6570-06-M

3

September 5, 1979.

FEDERAL ENERGY REGULATORY COMMISSION.

TIME AND DATE: September 12, 1979, 10 a.m.

PLACE: 825 North Capitol Street, NE., Washington, D.C. 20426, Room 9306.

STATUS: Open.

MATTERS TO BE CONSIDERED: Agenda.

Note.—Items listed on the agenda may be deleted without further notice.

CONTACT PERSON FOR MORE INFORMATION: Kenneth F. Plumb, Secretary, Telephone (202) 275-4166.

This is a list of matters to be considered by the Commission. It does not include a listing of all papers relevant to the items on the agenda; however, all public documents may be examined in the Office of Public Information.

Power Agenda—338th Meeting, September 12, 1979, Regular Meeting (10 a.m.)

CAP-1. Docket Nos. ER76-306, et al., New England Power Co.

CAP-2. Docket Nos. ER79-216 and ER79-217, Boston Edison Co.

CAP-3. Docket No. ER78-514, Superior Water, Light & Power Co.

Gas Agenda—338th Meeting, September 12, 1979, Regular Meeting

CAG-1. Docket No. CP76-104 (PGA No. 79-2), Pacific Interstate Transmission Co.

CAG-2. Docket No. RP74-100 (PGA No. 79-4), National Fuel Gas Supply Corp.

CAG-3. Docket Nos. RP72-134, RP75-46 and RP77-17 (PGA No. 79-5 and DCA No. 79-3), Eastern Shore Natural Gas Co.

CAG-4. Docket No. RP72-155, El Paso Natural Gas Co.

CAG-5. Docket Nos. RP72-142, RP76-135 and RP78-76 (PGA79-2A and AP79-2A), Cities Service Gas Co.

CAG-6. Docket No. OR79-3, Lakehead Pipe Line Co.

CAG-7. Special report by Tenneco, Inc., concerning J. R. McDermott & Co., Inc., and Brown and Root, Inc. matters.

CAG-8. Docket Nos. CI76-678 and CI76-722, Tenneco, Inc. Docket No. CI76-784, Texaco, Inc.

CAG-9. Docket No. CI78-1046, Mesa Petroleum Co. Docket No. CI78-654, Shell Oil Co. Docket No. C579-365, Orville C. Rogers. Docket No. G-14614, American Petrofina Co. of Texas, et al. Docket No. CI77-655, Aminoil USA, Inc. Docket No. CI78-1202, Amoco Production Co. Docket No. CI79-332, Mesa Petroleum Co. Docket No. CI74-528, Exxon Corp. Docket No. CI76-721, Amoco production Co. Docket No. CI78-416, Sun Oil Co. Docket No. CI63-1050, Northern Natural Producing. Docket No. CI78-1245, Phillips Petroleum Co. Docket No. CI78-617, Atlantic Richfield Co. Docket No. CI74-567, Chevron U.S.A. Inc. Docket No. CI77-611 and CI77-612, Pennzoil Louisiana Offshore, Inc. Docket No. CI77-654, Southland Royalty Co. Docket No. CI74-567, Chevron U.S.A. Inc. Docket No. CI78-616, Hondo Oil & Gas Co. Docket No. CI77-691, Columbia Gas Development Corp. Docket No. CI78-33, Amoco Production Co., operator, et al. Docket No. CI78-933, Aminoil USA, Inc. Docket No. CI76-586, Atlantic Richfield Co., et al. Docket No. CI79-515, Louisiana Land Offshore Exploration Co., Inc. Docket No. CI67-808, Shell Oil Co. (operator), et al. Docket No. CI79-519, Texaco, Inc. Docket No. CI79-493, Texas Eastern Exploration Co. Docket No. CI67-850, Amoco Production Co. Docket No. CI79-513, The Louisiana Land and Exploration Co. Docket No. CI72-440, Amoco Production Co. Docket No. CI78-655, Sun Oil Co.

CAG-10. Docket No. CP76-285, Mountain Fuel Resources, Inc. Docket No. CP76-388, Mountain Fuel Supply Co. Docket No. CP76-389, Northwest Pipeline Corp. Docket No. CP77-289, El Paso Natural Gas Co. Docket No. CP76-512, Clay Basin Storage Co. Docket No. CP76-87 (Rhodes Reservoir), El Paso Natural Gas Co. Docket No. CP78-172 (Barker Creek Dome), El Paso Natural Gas Co. Docket No. CP78-257 (Barker Creek Dome), Western Gas Interstate Co. Docket No. CI78-506, Supron Energy Corp.

CAG-11. Docket No. CP79-362, Michigan Wisconsin Pipe Line Co.
CAG-12. Docket No. CP79-265, McCulloch Interstate Gas Corp.
CAG-13. Docket No. CP79-263, Natural Gas Pipeline Co. of America, Columbia Gulf Transmission Co., Northern Natural Gas Co. and Trunkline Co.
CAG-14. Docket Nos. CP79-290, RP79-69 and RP79-49, Equitable Gas Co.
CAG-15. Docket No. CP79-245, Western Transmission Corp.

Power Agenda—338th Meeting, September 12, 1979, Regular Meeting

I. Licensed Project Matters

P-1. Project No. 199, South Carolina Public Service Authority. Docket No. E-9110, James H. Quackenbush v. South Carolina Public Service Authority.

II. Electric Rate Matters

ER-1. Docket No. ER79-535, Kansas City Power & Light Co.
ER-2. Docket Nos. E-8187, E-8700, ER76-203, ER76-238 and ER78-516, Boston Edison Co.
ER-3. Docket No. E-7777 (Phase II), Pacific Gas & Electric Co. Docket No. E-7796, Pacific Power & Light Co.
ER-4. Docket No. E-9578 (Phase I), Texas Power & Light Co.
ER-5. Docket No. ER79-279, Virginia Electric & Power Co.
ER-6. Docket No. EL79-16, Otter Tail Power Co.
ER-7. Docket No. ID-1758, Charles T. Fisher, III.
ER-8. Docket No. ER77-488 and ER78-520 (Phase I), El Paso Electric Co.

Miscellaneous Agenda—338th Meeting, September 12, 1979, Regular Meeting

M-1. Reserved.
M-2. Reserved.
M-3. Docket No. GP79-30, State of Utah § 103 NGPA Determination American Quasar Petroleum, Co. No. Uper 5-1 Well.
M-4. Docket No. GP79-40, United States Geological Survey § 103 NGPA Determination Belco Petroleum Corp. Chapita Wells Unit 32-21 API No. 43-047-30233.
M-5. Notice of Well Determinations.
M-6. Docket No. GP79-18, Guernsey Petroleum Corp.
M-7. Docket No. RM79- , final rule promulgating subpart I of part 271 concerning § 109 of the Natural Gas Policy Act of 1978.
M-8. Docket No. RM79-47, Budget-Type Applications: Gas Supply Facilities—Amendments to scope of existing Docket No. RM79-43, amendments to subpart A, part 157 of the regulations implementing the Natural Gas Act.
M-9. Docket No. RM79-14, regulations implementing the incremental pricing provisions of the Natural Gas Policy Act of 1978.
M-10. Docket No. RM79-21, regulations implementing alternative fuel cost ceiling on incremental pricing under the Natural Gas Policy Act.
M-11. Docket No. RM79-45, exemption from incremental pricing for load-balancing facilities which burn coal.
M-12. Docket No. RM79-46, exemption from incremental pricing for load-balancing facilities which burn oil.
M-13. Docket No. RM79-48, new small boil exemption from incremental pricing.
M-14. Docket No. RM79-77, rule required under section 202 of the Natural Gas Policy Act of 1978.

Gas Agenda—338th meeting, September 12, 1979, Regular Meeting

I. Pipeline Rate Matters

RP-1. Docket No. RP73-65 (PGA77-4), Columbia Gas Transmission Corp.
RP-2. Docket No. RP72-156 (PGA79-1A) Texas Gas Transmission Corp.
RP-3. Docket No. RP79-76, Cities Service Gas Co.
RP-4. Docket No. RP72-133 (PGA77-2), United Gas Pipe Line Co.

II. Producer Matters

CI-1. Docket No. CI75-45, et al., Tenneco Oil Co., et al.

III. Pipeline Certificate Matters

CP-1. Docket No. CP77-403 and CP77-547, Transcontinental Gas Pipe Line Corp.

Kenneth F. Plumb,
Secretary.

[S-1742-79 Filed 9-6-79; 11:35 am]
BILLING CODE 6450-01-M

4

FEDERAL ENERGY REGULATORY COMMISSION.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: 44 FR 51397, Aug. 31, 1979.

PREVIOUSLY ANNOUNCED TIME AND DATE OF MEETING: September 5, 1979, 10 a.m.

CHANGE IN MEETING: Addition to the agenda meeting of Sept. 5, 1979.

Item No., Docket No., and Company

M-12.—Depco, Inc., Beall Federal Well No. 1 USGS—Albuquerque New Mexico Section 102 NGPA Determination FERC JD No. 79-13417 USGS Docket No. NM-368-79.
CI-1.—CI79-415, Continental Oil Co., CI79-532, Exxon Corp.

Kenneth F. Plumb,
Secretary.

[S-1748-79 Filed 9-6-79; 3:51 pm]
BILLING CODE 6450-01-M

5

FEDERAL HOME LOAN BANK BOARD.

TIME AND DATE: 9:30 a.m., September 13, 1979.

PLACE: 1700 G Street, NW., Sixth Floor, Washington, D.C.

STATUS: Open meeting.

CONTACT PERSON FOR MORE INFORMATION: Franklin Q. Bolling, (202-377-6677).

MATTERS TO BE CONSIDERED.

Application for Permission to Incur Debt—Guarantee Financial Corporation of California, Fresno, California

Application for Bank Membership—Erie Savings Bank, Buffalo, New York

Application for Bank Membership and Insurance of Accounts—Security Savings and Loan Association, Hayes, Virginia

Application for Bank Membership, Insurance of Accounts and Preliminary Conversion to a Federal Mutual Charter—Montgomery Savings and Loan Association, Troy, North Carolina

Application for Appeal for Remission of Liquidity Deficiency Penalties—USLIFE Savings and Loan Association, Los Angeles, California

Application for Federal Savings and Loan Advisory Council Committee Travel Authorization

Application for Formal Conversion into a Federal Mutual Association—Kings Mountain Savings and Loan Association, Kings Mountain, North Carolina

September 6, 1979.

[S-1745-79 Filed 9-6-79; 3:08 pm]
BILLING CODE 6720-01-M

6

FEDERAL HOME LOAN BANK BOARD.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: Vol. 44, FR Page 52073-52074, September 6, 1979.

PREVIOUSLY ANNOUNCED TIME AND DATE OF MEETING: 9:30 a.m., September 5, 1979.

PLACE: 1700 G Street NW., Sixth Floor, Washington, D.C.

STATUS: Open meeting.

CONTACT PERSON FOR MORE INFORMATION: Franklin O. Bolling, (202-377-6677).

CHANGES IN THE MEETING: The following item was added to the agenda for the open meeting—Report Concerning Sale of FSLIC Asset.

ANNOUNCEMENT IS BEING MADE AT THE EARLIEST PRACTICABLE TIME.

September 6, 1979.

[S-1747-79 Filed 9-6-79; 3:08 pm]
BILLING CODE 6720-01-M

7

FEDERAL MARITIME COMMISSION.

TIME AND DATE: September 12, 1979, 10 a.m.

PLACE: Room 12126—1100 L Street, NW., Washington, D.C. 20573.

STATUS: Parts of the meeting will be open to the public.

The rest of the meeting will be closed to the public.

MATTERS TO BE CONSIDERED:

Portions Open to the Public

1. Agreement No. 10361 between Farrell Lines and Compagnie Maritime Zairoise and

Agreement No. 10362 between Delta Steamship Lines, Inc. and Compagnie Maritime Zairoise establishing agency/husbanding agreements.

2. Agreement No. 9615–28: Modification of the Iberian/U.S. North Atlantic Freight Conference to conform to General Order 7.

3. Petition of Government of the Virgin Islands for reconsideration of the disposition of protest of initial service of Puerto Rico Maritime Shipping Authority to Virgin Islands.

4. Special Docket No. 647: Application of American President Lines, Ltd., for the Benefit of Beverly Coat Hanger Company—Review of initial decision.

Portions Closed to the Public

1. Docket No. 79–76: Pacific Westbound Conference Agreement No. 57–115—Consideration of the record.

2. Docket No. 77–50: North Carolina State Ports Authority International Longshoremen's Association, AFL–CIO, Local 1426, International Longshoremen's Association, AFL–CIO Local 1426–A, Warehousemen v. Dart Containerline Company, Limited—Consideration of petition of respondent for stay or order.

CONTACT PERSON FOR MORE INFORMATION: Francis C. Hurney, Secretary, (202) 523–5725.

[S-1743-79 Filed 9-6-79; 11:35 am]

BILLING CODE 6730-01-M

8

NATIONAL SCIENCE BOARD.

DATE AND TIME: September 20, 1979, 1 p.m. Open Session. September 21, 1979 9 a.m. Closed Session.

PLACE: National Science Foundation, Rm 540, 1800 G. Street, N.W. Washington, D.C.

STATUS: Parts of this meeting will be open to the public. The rest of the meeting will be closed to the public.

MATTERS TO BE CONSIDERED AT THE OPEN SESSION:

1. Minutes—Open Session—208th Meeting
2. Chairman's Report
3. Director's Report—
a. Report on Grant & Contract Activity—8/16–9/19, 1979
b. Organizational and Staff Changes
c. Congressional and Legislative Matters
d. NSF Budget for Fiscal Year 1980
4. Board Committees—Reports on Meetings—
a. Executive Committee
b. Planning and Policy Committee
c. Programs Committee
d. Committee on Minorities and Women in Science
e. Committee on Role of NSF in Basic Research
f. Ad Hoc Committee on Big and Little Science
g. Ad Hoc Committee on Deep Sea and Ocean Margin Drilling Programs
h. Ad Hoc Committee on NSB Nominees
5. NSF Advisory Groups
6. Program Review—Policy Research and Analysis
7. Board Representation at Future Site Visits to Materials Research Laboratories
8. Board Representation at Semiannual Review: Very Large Array at Socorro, New Mexico
9. Grants, Contracts, and Programs—Information Item
10. Review of NSF Act of 1950, as Amended
11. Other Business
12. Next Meetings: National Science Board, 210th Meeting, October 18–19, 1979

MATTERS TO BE CONSIDERED AT THE CLOSED SESSION:

A. Minutes—Closed Session—208th Meeting
B. Grants, Contracts, and Programs
C. Nominations: NSB, NSF Assistant Directors, and Alan T. Waterman Award Committee
D. NSB Annual Reports
E. NSF Budgets for Fiscal Year 1981 and Subsequent Years

CONTACT PERSON FOR MORE INFORMATION: Miss Vernice Anderson, Executive Secretary, (202) 632–5840.

[S-1741-79 Filed 9-6-79; 10:14 am]

BILLING CODE 7555-01-M

9

NUCLEAR REGULATORY COMMISSION.

TIME AND DATE: September 5 and 6, 1979.

PLACE: Commissioners' Conference Room, 1717 H St., NW, Washington, D.C.

STATUS: Open/Closed (Changes).

MATTERS TO BE CONSIDERED:

Wednesday, September 5, 2:30 p.m.

The meeting titled "Discussion of Proceeding to Assess Commission Confidence in Safe Disposal of Nuclear Wastes" (Public meeting) was cancelled. The Affirmation Session (Public meeting) will take its place.

Thursday, September 6, 9:30 a.m.

The Briefing by H. Denton on Conclusions of TMI Lessons Learned Recommendations (Public meeting) will begin at 9:30 a.m. instead of 10 a.m., as previously announced.

Thursday, September 6, 3 p.m.

Discussion of Personnel Matter (Approximately 1½ hours—Closed-Ex-6—Continued from 9/4).

CONTACT PERSON FOR MORE INFORMATION: Walter Magee, (202) 634–1410.

Roger M. Tweed,

Office of the Secretary.

September 4, 1979.

[S-1744-79 Filed 9-6-79; 11:54 am]

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Part II

Environmental Protection Agency

Standards of Peformance for New Stationary Sources; Gas Turbines

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1276-2]

Standards of Performance for New Stationary Sources; Gas Turbines

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This rule establishes standards of performance which limit emissions of nitrogen oxides and sulfur dioxide from new, modified and reconstructed stationary gas turbines. The standards implement the Clean Air Act and are based on the Administrator's determination that stationary gas turbines contribute significantly to air pollution. The intended effect of this regulation is to require new, modified and reconstructed stationary gas turbines to use the best demonstrated system of continuous emission reduction.

EFFECTIVE DATE: September 10, 1979.

ADDRESSES: The Standards Support and Environmental Impact Statement (SSEIS) may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711 (specify *Standards Support and Environmental Impact Statement, Volume 2: Promulgated Standards of Performance for Stationary Gas Turbines*, EPA-450/2-77-017b).

FOR FURTHER INFORMATION CONTACT: Don R. Goodwin, Director, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone No. (919) 541-5271.

SUPPLEMENTARY INFORMATION:

The Standards

The promulgated standards apply to all new, modified, and reconstructed stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (about 1,000 horsepower). The standards apply to simple and regenerative cycle gas turbines and to the gas turbine portion of a combined cycle steam/electric generating system.

The promulgated standards limit the concentration of nitrogen oxides (NO_x) in the exhaust gases from stationary gas turbines with a heat input from 10.7 to and including 107.2 gigajoules per hour (about 1,000 to 10,000 horsepower), from offshore platform gas turbines, and from stationary gas turbines used for oil or gas transportation and production not located in a Metropolitan Statistical Area (MSA), to 0.0150 percent by volume (150 PPM) at 15 percent oxygen on a dry basis. The promulgated standards also limit the concentration of NO_x in the exhaust gases from stationary gas turbines with a heat input greater than 107.2 gigajoules per hour, and from stationary gas turbines used for oil or gas transportation and production located in an MSA, to 0.0075 percent by volume (75 PPM) at 15 percent oxygen on a dry basis (see Table 1 for summary of NO_x emission limits). Both of these emission limits (75 and 150 PPM) are adjusted upward for gas turbines with thermal efficiencies greater than 25 percent using an equation included in the promulgated standards. These emission limits are also adjusted upward for gas turbines burning fuels with a nitrogen content greater than 0.015 percent by weight using a fuel-bound nitrogen allowance factor included in the promulgated standards, or a "custom" fuel-bound nitrogen allowance factor developed by the gas turbine manufacturer and approved for use by EPA. Custom fuel-bound nitrogen allowance factors must be substantiated with data and approved for use by the Administrator before they may be used for determining compliance with the standards.

The promulgated NO_x emission limits are referenced to International Standard Organization (ISO) standard day conditions of 288 degrees Kelvin, 60 percent relative humidity, and 101.3 kilopascals (1 atmosphere) pressure. Measured NO_x emission levels, therefore, are adjusted to ISO reference conditions by use of an ambient condition correction factor included in the standards, or by a custom ambient condition correction factor developed by the gas turbine manufacturer and approved for use by EPA. Custom ambient condition correction factors can only include the following variables: combustor inlet pressure, ambient air pressure, ambient air humidity, and ambient air temperature. These factors must be substantiated with data and approved for use by the Administrator before they may be used for determining compliance with the standards.

Stationary gas turbines with a heat input at peak load from 10.7 to, and including, 107.2 gigajoules per hour are to be exempt from the NO_x emission limit included in the promulgated standards for five years from the date of proposal of the standards (October 3, 1977). New gas turbines with this heat input at peak load which are constructed, or existing gas turbines with this heat input at peak load which are modified or reconstructed during this five-year period do not have to comply with the NO_x emission limit included in the promulgated standards at the end of this period. Only those new gas turbines which are constructed, or existing gas turbines which are modified or reconstructed, following this five-year period must comply with the NO_x emission limit.

Emergency-standby gas turbines, military training gas turbines, gas turbines involved in certain research and development activities, and firefighting gas turbines are exempt from compliance with the NO_x emission limits included in the promulgated standards. In addition, stationary gas turbines using wet controls are temporarily exempt from the NO_x emission limit during those periods when ice fog created by the gas turbine is deemed by the owner or operator to present a traffic hazard, and during periods of drought when water is not available.

None of the exemptions mentioned above apply to the sulfur dioxide (SO_2) emission limit. The promulgated standards limit the SO_2 concentration in the exhaust gases from stationary gas turbines with a heat input at peak load of 10.7 gigajoules per hour or more to 0.015 percent by volume (150 PPM) corrected to 15 percent oxygen on a dry basis. The standards include an alternative SO_2 emission limit on the sulfur content of the fuel of 0.8 percent sulfur by weight (see Table 1 for summary of exemptions and SO_2 emission limits).

Table 1.—*Summary of Gas Turbine New Source Performance Standard*

Gas turbine size and usage	NO_x emission limit [1]	Applicability date for NO_x	SO_2 emission limit	Applicability date for SO_2
Less than 10.7 gigajoules/hour (all uses)	None	Standard does not apply.	None	Standard does not apply.
Between 10.7 and 107.2 gigajoules/hour (all uses).	150 ppm	October 3, 1982	150 ppm SO_2 or fire a fuel with less than 0.8% sulfur.	October 3, 1977
Greater than or equal to 107.2 gigajoules/hour:				
1. Gas and oil transportation or production not located in an MSA.	150 ppm	October 3, 1977	Same as above	October 3, 1977
2. Gas and oil transportation or production located in an MSA.	75 ppm	October 3, 1977	Same as above	October 3, 1977
3. All other uses	75 ppm	October 3, 1977	Same as above	October 3, 1977
Emergency standby, firefighting, military (except for garrison facility), military training, and research and development turbines.	None	Standard does not apply.	Same as above	October 3, 1977

[1] NO_x emission limit adjusted upward for gas turbines with thermal efficiencies greater than 25 percent and for gas turbines firing fuels with a nitrogen content of more than 0.015 weight percent. Measured NO_x emissions adjusted to ISO conditions in determining compliance with the NO_x emission limit.

Environmental, Energy, and Economic Impact

The promulgated standards will reduce NO_x emissions by about 190,000 tons per year by 1982 and by 400,000 tons per year by 1987. This reduction will be realized with negligible adverse solid waste and noise impacts.

The adverse water pollution impact associated with the promulgated standards will be minimal. The quantity of water or steam required for injection into the gas turbine to reduce NO_x emissions is less than 5 percent of the water consumed by a comparable size steam/electric power plant using cooling towers. There will be no adverse water pollution impact associated with those gas turbines which employ dry NO_x control technology.

The energy impact associated with the promulgated standards will be small. Gas turbine fuel consumption could increase by as much as 5 percent in the worst cases. The actual energy impact depends on the rate of water injection necessary to comply with the promulgated standards. Assuming the "worst case," however, the standards would increase fuel consumption of large stationary gas turbines (i.e., greater than 10,000 horsepower) by about 5,500 barrels of fuel oil per day in 1982. The standards would increase fuel consumption of small stationary gas turbines (i.e., less than 10,000 horsepower) by about 7,000 barrels of fuel oil per day in 1987. This is equivalent to an increase in projected 1982 and 1987 national crude oil consumption of less than 0.03 percent. As mentioned, these estimates are based on "worst case" assumptions. The actual energy impact of the promulgated standard is expected to be much lower than these estimates because most gas turbines will not experience anywhere near a 5 percent fuel penalty due to water or steam injection. In addition, many gas turbines will comply with the standards using dry control, which in most cases has no energy penalty.

The economic impact associated with the promulgated standards is considered reasonable. The standards will increase the capital costs or purchase price of a gas turbine for most installations by about 1 to 4 percent. The annualized costs will be increased by about 1 to 4 percent, with the largest application, utilities, realizing less than a 2 percent increase.

The promulgated standards will increase the total capital investment requirements for users of large stationary gas turbines by about 36 million dollars by 1982. For the period 1982 through 1987, the standards will increase the capital investment requirements for users of both large and small stationary gas turbines by about 67 million dollars. Total annualized costs for these users of stationary gas turbines will be increased by about 11 million dollars in 1982 and by about 30 million dollars in 1987. These impacts will result in price increases for the end products or services provided by industrial and commercial users of stationary gas turbines ranging from less than 0.01 percent in the petroleum refining industry, to about 0.1 percent in the electric utility industry.

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the **Federal Register** of meetings of the National Air Pollution Control Techniques Advisory Committee to discuss the standards recommended for proposal. These meetings occurred on February 21, 1973; May 30, 1973; and January 9, 1974. The meetings were open to the public and each attendee was given ample opportunity to comment on the standards recommended for proposal. The standards were proposed and published in the **Federal Register** on October 3, 1977. Public comments were solicited at that time and, when requested, copies of the Standards Support and Environmental Impact Statement (SSEIS) were distributed to interested parties. The public comment period extended from October 3, 1977, to January 31, 1978.

Seventy-eight comment letters were received on the proposed standards of performance. These comments have been carefully considered and, where determined to bé appropriate by the Administrator, changes have been made in the standards which were proposed.

Significant Comments and Changes to the Proposed Regulation

Comments on the proposed standards were received from electric utilities, oil and gas producers, gas turbine manufacturers, State air pollution control agencies, trade and professional associations, and several Federal agencies. Detailed discussion of these comments can be found in Volume 2 of the SSEIS. The major comments can be combined into the following areas: general, emission control technology, modification and reconstruction, economic impacts, environmental impacts, energy impacts, and test methods and monitoring.

General

Small stationary gas turbines (i.e, those with a heat input at peak load between 10.7 and 107.2 gigajoules per hour—about 1,000 to 10,000 horsepower) are exempt from the standards for a period of five years following the date of proposal. Some commenters felt it was not clear whether small gas turbines would be required to retrofit NO_x emissions controls after the exemption period ended. These commenters felt this was not the intent of the standards and they recommended that this point be clarified.

The intent of both the proposed and the promulgated standards is to consider small gas turbines which have commenced construction on or before the end of the five year exemption period as existing facilities. These facilities will not have to retrofit at the end of the exemption period. This point has been clarified in the promulgated standards.

Several commenters requested exemptions for temporary and intermittent operation of gas turbines to permit research and development into advanced combustion techniques under full scale conditions.

This is considered a reasonable request. Therefore, gas turbines involved in research and development for the purpose of improving combustion efficiency or developing emission control technology are exempt from the NO_x emission limit in the promulgated standards. Gas turbines involved in this type of research and development generally operate intermittently and on a temporary basis. The standards have been changed, therefore, to allow exemptions in such situations on a case-by-case basis.

Emissions Control Technology

The selection of wet controls, or water injection, as the best system of emission reduction for stationary gas turbines was criticized by a number of commenters. These commenters pointed out that although dry controls will not reduce emissions as much as wet controls, dry controls will reduce NO_x emissions without the objectionable results of water injection (i.e., increased fuel consumption and difficulty in securing water of acceptable quality). These commenters, therefore, recommended postponement of standards until dry controls can be implemented on gas turbines.

As pointed out in Volume 1 of the SSEIS, a high priority has been established for control of NO_x emissions. Wet and dry controls are considered the only viable alternative control techniques for reducing NO_x emissions from gas turbines. Control of NO_x emissions by either of these two alternatives clearly favored the development of the standards of performance based on wet controls from an environmental viewpoint. Reductions in NO_x emissions of more than 70 percent have been demonstrated using wet controls on many large gas turbines used in utility and industrial applications. Thus, wet controls can be applied immediately to large gas turbines, which account for 85–90 percent of NO_x emissions from gas turbines.

The technology of wet control is the same for both large and small gas turbines. The manufacturers of small gas turbines, however, have not experimented with or developed this technology to the same extent as the manufacturers of large gas turbines. In addition, small gas turbines tend to be produced or more of an assembly line basis than large gas turbines. Consequently, the manufacturers of small gas turbines need a lead time of five years (based on their estimates) to design, test, and incorporate wet controls on small gas turbines.

Even with a five-year delay in application of standards to small gas turbines, standards of performance based on wet controls will reduce national NO_x emissions by about 190,000 tons per year by 1982. Therefore, the reduction in NO_x emissions resulting from standards based on wet controls is significant.

Dry controls have demonstrated NO_x emissions reduction of only about 40 percent in laboratory and combustor rig tests. Because of the advanced state of research and development into dry control by the manufacturers of large gas turbines, the much longer lead time involved in ordering large gas turbines, and the greater attention that can be given to "custom" engineering designs of large gas turbines, dry controls can be implemented on large gas turbines immediately. Manufacturers of small gas turbines, however, estimate that it would take them as long to incorporate dry controls as wet controls on small gas turbines. Basing the standards only on dry controls, therefore, would significantly reduce the amount of NO_x emission reductions achieved.

The economic impact of standards based on wet controls is considered reasonable for large gas turbines. (See Economic Impact Discussion.) Thus, wet controls represent ". . . the best system of continuous emission reduction . . . (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) . . ." for large gas turbines.

The economic impact of standards based on wet controls, however, is considered unreasonable for small gas turbines, gas turbines located on offshore platforms, and gas turbines employed in oil or gas production and transportation which are not located in a Metropolitan Statistical Area. The economic impact of standards based on dry controls, on the other hand, is considered reasonable for these gas turbines. (See Economic Impact Discussion.) Thus, dry controls represent ". . . the best system of continuous emission reduction . . . (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) . . ." for small gas turbines, gas turbines located on offshore platforms, and gas turbines employed in oil or gas production and transportation which are not located in a Metropolitan Statistical Area.

Volume 1 of the SSEIS summarizes the data and information available from the literature and other nonconfidential sources concerning the effectiveness of dry controls in reducing NO_x emissions from stationary gas turbines. More recently, additional data and information have been published in the Proceedings of the Third Stationary Source Combustion Symposium (EPA-600/7-79-050C), Advanced Combustion Systems for Stationary Gas Turbines (interim report) prepared by the Pratt and Whitney Aircraft Group for EPA (Contract 68-02-2136), "Experimental Clean Combustor Program Phase III" (NASA CR-135253) also prepared by the Pratt and Whitney Aircraft Group for the National Aeronautics and Space Administration (NASA), and "Aircraft Engine Emissions" (NASA Conference Publication 2021). These data and information show that dry controls can reduce NO_x emissions by about 40 percent. Multiplying this reduction by a typical NO_x emission level from an uncontrolled gas turbine of about 250 ppm leads to an emission limit for dry controls of 150 ppm. This, therefore, is the numerical emission limit included in the promulgated standards for small gas turbines, gas turbines located on offshore platforms, and gas turbines employed in oil or gas production or transportation which are not located in Metropolitan Statistical Areas.

The five-year delay from the date of proposal of the standards in the applicability date of compliance with the NO_x emission limit for small gas turbines has been retained in the promulgated standards. As discussed above, manufacturers of small gas turbines have estimated that it will take this long to incorporate either wet or dry controls on these gas turbines.

Several commenters criticized the fuel-bound nitrogen allowance included in the proposed standards. It was felt that greater flexibility in the equations used to calculate the fuel-bound nitrogen NO_x emissions contribution should be permitted, due to the limited data on conversion of fuel-bound nitrogen to NO_x. These commenters recommended that manufacturers of gas turbines be allowed to develop their own fuel-bound nitrogen allowance.

As discussed in Volume I of the SSEIS, the reaction mechanism by which fuel-bound nitrogen contributes to NO_x emissions is not fully understood. In addition, emission data are limited with respect to fuels containing significant amounts of fuel-bound nitrogen. The problem of quantifying the fuel-bound nitrogen contribution to total NO_x emissions is further complicated by the fact that the amount of nitrogen in the fuel has an effect on this contribution.

In light of this sparsity of data, the commenters' recommendations seem reasonable. Therefore, a provision has been added to the standards to allow manufacturers to develop custom fuel-bound nitrogen allowances for each gas turbine model. The use of these factors, however, must be approved by the Administrator before the initial performance test required by Section 60.8 of the General Provisions. Petitions by manufacturers for approval of the use of custom fuel-bound nitrogen allowance factors must be supported by data which clearly provide a basis for determining the contribution of fuel-bound nitrogen to total NO_x emissions. In addition, in no case will EPA approve a custom fuel-bound nitrogen allowance factor which would permit an increase in NO_x emissions of more than 50 ppm. (See Energy Impact Discussion.) Notice of approval of the use of these factors for various gas turbine models will be given in the **Federal Register.**

Modification and Reconstruction

Some commenters felt that existing gas turbines which now burn natural gas and are subsequently altered to burn oil should be exempt from consideration as modifications. The high cost and technical difficulties of compliance with the standards would discourage fuel switching to conserve natural gas supplies.

As outlined in the General Provisions of 40 CFR Part 60, which are applicable to all standards of performance, most changes to an existing facility which result in an increase in emission rate to the atmosphere are considered modifications. However, according to section 60.14(e)(4) of the General Provisions, the use of an alternative fuel or raw material shall not be considered a modification if the existing facility was designed to accommodate that alternative use. Therefore, if a gas turbine is designed to fire both natural gas and oil, then switching from one fuel to the other would not be considered a modification even if emissions were increased. If a gas turbine that is not designed for firing both fuels is switched from firing natural gas to firing oil, installation of new injection nozzles which increase mixing to reduce NO_x production, or installation of new NO_x combustors currently on the market, would in most cases maintain emissions at their previous levels. Since emissions would not increase, the gas turbine would not be considered modified, and the real impact of the standards on gas turbines switching from natural gas to oil will probably be quite small. Therefore, no special provisions for fuel switching have been included in the promulgated standards.

Economic Impact

Several commenters stated that water injection could increase maintenance costs significantly. One reason cited was that chemicals and minerals in the water would likely be deposited on internal surfaces of gas turbines, such as turbine blades, leading to downtime for repair and cleaning. In addition, the commenters felt that higher maintenance requirements could be expected due to the increased complexity of a gas turbine with water injection.

As pointed out in Volume 1 of the SSEIS, to avoid deposition of chemicals and minerals on gas turbine blades, the water used for water injection must be treated. Costs for water treatment were included in the overall costs of water injection and, for large gas turbines, these costs are considered reasonable.

Actual maintenance and operating costs for gas turbines operating with water or steam injection are limited. Several major utilities, however, have accumulated significant amounts of operating time on gas turbines using water or steam injection for control of NO_x emissions. There have been some problems attributable to water or steam injection, but based on the data available, these problems have been confined to initial periods of operation of these systems. Most of these reported problems such as turbine blade damage, flame-outs, water hammer damage, and ignition problems, were easily corrected by minor redesign of the equipment hardware. Because of the knowledge gained from these systems, such problems should not arise in the future.

As mentioned, some utilities have accumulated substantial operating experience without any significant increase in maintenance or operating costs or other adverse effects. One utility, for example, has used water injection on two gas turbines for over 55,000 hours without making any major changes to their normal maintenance and operating procedures. They followed procedures essentially identical to those required for a similar gas turbine not using water injection, and the plant experienced no outages attributable to the water injection system. Another company has accumulated over 92,000 hours of operating time with water injection on 17 gas turbines with approximately 116 hours of outage attributable to their water injection system. Increased maintenance costs which can be attributed to these water injection systems are not available, as such costs were not accounted for separately from normal maintenance. However, they were not reported as significant.

Some commenters exresssed the opinion that the cost estimates for controlling NO_x emissions from large gas turbines were too low. Accordingly, these commenters felt that wet control technology should not be the basis of the standards for large stationary gas turbines.

The costs associated with wet control technology for large gas turbines were reassessed. In a few cases, it appeared the water-to-fuel ratio used in Volume 1 of the SSEIS was somewhat low. In these cases, the capital and annualized operating costs associated with wet control on large gas turbines were revised to reflect injection of more water into the gas turbine. None of these revisions, however, resulted in a significant change in the projected economic impact of wet controls on large gas turbines. Thus, depending on the size and end use of large gas turbines, wet controls are still projected to increase capital and annualized operating costs by no more than 1 to 4 percent. Increases of this order of magnitude are considered reasonable in light of the 70 percent reduction in NO_x emissions achieved by wet controls. Consequently, the basis of the promulgated standards for large gas turbines remains the same as that for the proposed standards—wet controls.

A number of commenters also expressed the opinion that the cost estimates for wet controls to reduce NO_x emissions from small gas turbines were too low. Therefore, the standards for small gas turbines should not be based on wet controls.

Information included in the comments submitted by manufacturers of small gas turbines indicated the costs of redesigning these gas turbines for water injection are much greater than those included in Volume 1 of the SSEIS. Consequently, it appears the costs of water injection would increase the capital cost of small gas turbines by about 16 percent, rather than about 4 percent as originally estimated. Despite this increase in capital costs, it does not appear water injection would increase the annualized operating costs of small gas turbines by more than 1 to 4 percent as originally estimated, due to the predominance of fuel costs in operating costs. An increase of 16 percent in the capital cost of small gas turbines, however, is considered unreasonable.

Very little information was presented in Volume 1 of the SSEIS concerning the costs of dry controls. The conclusion was drawn, however, that these costs would undoubtedly be less than those associated with wet controls.

Little information was also included in the comments submitted by the manufacturers of small gas turbines concerning the costs of dry controls. Most of the cost information dealt with the costs of wet controls. One manufacturer, however, did submit limited information which appears to indicate that the capital cost impact of dry controls on small gas turbines might be only a quarter of that of wet controls. Thus, dry controls might increase the capital costs of small gas turbines by only about 4 percent. The potential impact of dry controls on annualized operating costs would certainly be no greater than wet controls, and would probably be much less. Consequently, it appears dry controls might increase the capital costs of small gas turbines by about 4 percent and the annualized operating costs by about 1 to 4 percent.

The magnitude of these impacts is essentially the same as those originally associated with wet controls in Volume 1 of the SSEIS, and they are considered reasonable. Consequently, the basis of the promulgated standards for small gas turbines is dry controls.

A number of commenters stated that the costs associated with wet controls on gas turbines located on offshore platforms, and in arid and remote regions were unreasonable. These commenters felt that the costs of obtaining, transporting, and treating water in these areas prohibited the use of water injection.

As mentioned by the commenters, the costs associated with water injection on gas turbines in these locations are all related to lack of water of acceptable quality or quantity. Review of the costs included in Volume 1 of the SSEIS for water injection on gas turbines located on offshore platforms, indicates that the required expenditures for platform space were not incorporated into these estimates. Based on information included in the comments, platform space is very expensive, and averages approximately $400 per square foot. When this cost is included, the use water treatment systems to provide water for NO_x emissions control would increase the capital costs of a gas turbine located on an offshore platform by approximately 33 percent. This is considered an unreasonable economic impact.

Dry controls, unlike wet controls, would not require additional space on offshore platforms. Although most gas turbines located on offshore platforms would be considered small gas turbines under the standards, it is possible that some large gas turbines might be located on offshore platforms. Therefore, all the information available concerning the costs associated with standards based on dry controls for large gas turbines was reviewed.

Unfortunately, no additional information on the costs of dry controls was included in the comments submitted by the manufacturers of large gas turbines. As mentioned above, the information presented in Volume 1 of the SSEIS is very limited concerning the costs of dry controls, although the conclusion is drawn that these costs would undoubtedly be less than the costs of wet controls. It also seems reasonable to assume that the costs of dry controls on large gas turbines would certainly be less than the costs of dry controls on small gas turbines. Consequently, standards based on dry controls should not increase the capital and annualized operating costs of large gas turbines by more than the 1 to 4 percent projected for small gas turbines. This conclusion even seems conservative in light of the projected increase in capital and annualized operating costs for wet controls on large gas turbines of no more than 1 to 4 percent. In any event, the costs of standards based on dry controls for large gas turbines are considered reasonable. Therefore, the promulgated standards for gas turbines located on offshore platforms are based on dry controls.

In many arid and remote regions, gas turbines would have to obtain water by trucking, installing pipelines to the site, or by construction of large water reservoirs. While costs included in Volume 1 of the SSEIS do not show trucking of water to gas turbine sites to be unreasonable, these costs are not based on actual remote area conditions. That is, these costs are based on paved road conditions and standard ICC freight rates. Gas turbines located in arid and remote-regions, however, are not likely to have good access roads. Consequently, it is felt that the costs of trucking water, laying a water pipeline, or constructing a water reservoir would be unreasonable for most arid and remote areas.

As discussed above, the economic impact of standards based on dry controls for both large and small gas turbines in considered reasonable. Consequently, provisions have been included in the promulgated standards which essentially require gas turbines located in arid and remote areas to comply with an NO_x emission limit based on the use of dry controls. A number of options were considered before the specific provisions included in the promulgated standards were selected.

The first option considered was defining the term "arid and remote." While this is conceptually straightforward, it proved impossible to develop a satisfactory definition for regulatory purposes. The second option considered was defining all gas turbines located more than a certain distance from an adequate water supply as "arid and remote" gas turbines. Defining the distance and an adequate water supply, however, proved as impossible as defining the term "arid and remote." The third option considered was a case-by-case exemption for gas turbines where the costs of wet controls exceeded certain levels. This option, however, would provide incentive to owners and operators to develop grossly inflated costs to justify exemption and would require detailed analysis of each case on the part of the Agency to insure this did not occur. In addition, the numerous disputes and disagreements which would undoubtedly arise under this option would lead to delays and demands on limited resources within both the Agency and industry to resolve.

Analysis of the end use of most gas turbines located in arid and remote regions gave rise to a fourth option. Generally, gas turbines located in arid or remote regions are used for either oil and gas production, or oil and gas transportation. Consequently, the promulgated standards require gas turbines employed in oil and gas production or oil and gas transportation, which are not located in a Metropolitan Statistical Area (MSA), to meet an NO_x emission limit based on the use of dry controls. The promulgated standards, however, require gas turbines employed in oil and gas production or oil and gas transportation which are located in a MSA to meet the 75 ppm NO_x emission limit. This emission limit is based on the use of wet controls and in an MSA a suitable water supply for water injection will be available.

Environmental Impact

A number of commenters felt gas turbines used as "peaking" units should be exempt. Peaking units operate relatively few hours per year. According to commenters, use of water injection would result in a very small reduction in annual NO_x emissions and negligible improvement in ground level concentrations.

As pointed out in Volume 1 of the SSEIS, about 90 percent of all new gas turbine capacity is expected to be installed by electric utility companies to generate electricity, and possibly as much as 75 percent of all NO_x emissions from stationary gas turbines are emitted from these installations. Of these electric utility gas turbines, a large majority are used to generate power during periods of peak demand. Consequently, by their very nature, peaking gas turbines tend to operate when the need for emission control is greatest, that is, when power demand is highest and air quality is usually at its worst. Therefore, it does not seem reasonable to exempt peaking gas turbines from compliance with the standards.

A number of commenters also felt that small gas turbines should be exempt from the standards because they emit only about 10 percent of the total NO_x emissions from all stationary gas turbines and therefore, the environmental impact of not regulating these turbines would be small.

A high priority has been established for NO_x emission control and dry control techniques are considered a demonstrated and economically reasonably means for reducing NO_x emissions from small gas turbines. Therefore, the promulgated standards limit NO_x emissions from small gas turbines to 150 ppm based on the use of dry control technology.

Energy Impact

A number of writers commented on the potential impact of the standards on the use of the oil-shale, coal-derived, and other synthetic fuels. It was generally felt that these types of fuels should not be covered by the the standards at this time, since this could hinder their development.

Total NO_x emissions from any combustion source, including stationary gas turbines, are comprised of thermal NO_x and organic NO_x. Thermal NO_x is formed in a well-defined high temperature reaction between oxygen and nitrogen in the combustion air. Organic NO_x is produced by the combination of fuel-bound nitrogen with oxygen during combustion in a reaction that is not yet fully understood. Shale oil, coal-derived, and other synthetic fuels generally have high nitrogen contents and, therefore, will produce relatively high organic NO_x emissions when combusted.

Neither wet nor dry control technology for gas turbines is effective in reducing organic NO_x emissions. As discussed in Volume I of the SSEIS, as fuel-bound nitrogen increases, organic NO_x emissions from a gas turbine become the predominant fraction of total NO^2_x emissions. Consequently, emission standards must address in some manner the contribution to NO_x emissions of fuel-bound nitrogen.

Low nitrogen fuels, such as premium distillate fuel oil and natural gas, are now being fired in nearly all stationary gas turbines. Energy supply considerations, however, may cause more gas turbines to fire heavy fuel oils and synthetic fuels in the future. A standard based on present practice of firing low nitrogen fuels, therefore, would too rigidly restrict the use of high nitrogen fuel, especially in light of the uncertainty in world energy markets.

Since control technology is not in reducing organic NO_x emissions from gas turbines, the possibility of basing standards on removal of nitrogen from the fuel prior to combustion was considered. The cost of removing nitrogen from fuel oil, however, ranges from $2.00 to $3.00 per barrel. Another alternative considered was exempting gas turbines using high nitrogen fuels, as some commenters requested. Exempting gas turbines based on the type of fuel used, however, would not require the use of best control technology in all cases.

A third alternative considered was the use of a fuel-bound nitrogen allowance. Beyond some point it is simply not reasonable to allow combustion of high nitrogen fuels in gas turbines. In addition, high nitrogen fuels, including shale oil and coal-derived fuels, can be used in other combustion devices where some control of organic NO_x emissions is possible. Greater reduction of nationwide NO_x emissions could be achieved by utilizing these fuels in facilities where organic NO_x emission control is possible than in gas turbines where organic NO_x emissions are essentially uncontrolled. This approach, therefore, balances the trade-off between allowing unlimited selection of fuels for gas turbines controlling NO_x emissions.

A limited fuel-bound nitrogen allowance which would allow increased NO_x emissions above the numerical NO_x emissions limits including in the promulgated standards seems most reasonable. An upper limit on this allowance of 50 ppm NO_x was selected. Such a limit would allow approximately 50 percent of existing heavy fuel oils to be fired in stationary gas turbines. (See Volume I of the SSEIS.) This approach is considered a reasonable means of allowing flexibility in the selection of fuels while achieving reductions in NO_x emissions from stationary gas turbines. (See Control Technology for further discussion.)

A number of commenters felt the efficiency correction factor included in the standards should use the overall efficiency of a gas turbine installation rather than the thermal efficiency of the gas turbine itself. For example, many commenters recommended that the overall efficiency of a combined cycle gas turbine installation be used in this correction factor.

Section 111 of the Clean air Act requires that standards of performance for new sources reflect the use of the best system of emission reduction. With the few exceptions noted above, water injection is considered the best system of emission control for reducing NO_x emissions from stationary gas turbines. To be consistent with the intent of section 111, the standards must reflect the use of water injection independent of any ancillary waste heat recovery equipment which might be associated with a gas turbine to increase its overall efficiency. To allow an upward adjustment in the NO_x emission limit based on the overall efficiency of a combined cycle gas turbine could mean that water injection might not have to be applied to the gas turbine. Thus, the standards would not reflect the use of the best system of emission reduction. Therefore, the efficiency factor must be based on the gas turbine efficiency itself, not the overall efficiency of a gas turbine combined with other equipment.

Test Methods and Monitoring

A large number of commenters objected to the amount of monitoring required. The proposed standards called for daily monitoring of sulfur content, nitrogen content, and lower heating value of the fuel. The commenters were generally in favor of less frequent periodic monitoring.

These comments seem reasonable. Therefore, the standards have been changed to permit determination of sulfur content, nitrogen content, and lower heating value only when a fresh supply of fuel is added to the fuel storage facilities for a gas turbine. Where gas turbines are fueled without intermediate storage, such as along oil and gas transport pipelines, daily monitoring is still required by the standards unless the owner or operator can show that the composition of the fuel does not fluctuate significantly. In these cases, the owner or operator may develop an individual monitoring schedule for determining fuel sulfur content, nitrogen content, and lower heating value. These schedules must be substantiated by data and submitted to the Administrator for approval on a case-by-case basis.

Several commenters stated that the standards should be clarified to allow the performance test to be performed by the gas turbine manufacturer in lieu of the owner/operator. To simplify verification of compliance with the standards and to reduce costs to everyone involved, the recommendation was made that each gas turbine be performance tested at the manufacturer's site. The commenters maintained that gas turbines should not be required to undergo a performance test at the owner/operator's site if they have been shown to comply with the standard by the gas turbine manufacturer.

Section 111 of the Clean Air Act is not flexible enough to permit the use of a formal certification program such as that described by the commenter. Responsibility for complying with the standards ultimately rests with the owner/operator, not with the gas turbine manufacturers. The general provisions of 40 CFR Part 60, however, which apply to all standards of performance, allow the use of approaches other than performance tests to determine compliance on a case-by-case basis. The alternate approach must demonstrate to the Administrator's satisfaction that the facility is in compliance with the standard. Consequently, gas turbine manufacturers' tests may be considered, on a case-by-case basis, in lieu of performance tests at the owner/operator's site to demonstrate compliance with the standards. For a gas turbine manufacturers's test to be acceptable in lieu of a performance test, as a minimum the operating conditions of the gas turbine at the installation site would have to be shown to be similar to those during the manufacturer's test. In addition, this would not preclude the Administrator from requiring a performance test at any time to demonstrate compliance with the standards.

Miscellaneous

It should be noted that standards of performance for new stationary sources established under section 111 of the Clean Air Act reflect:

". . . application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environment impact and energy requirements) the Administrator determines has been adequately demonstrated. [section 111(a)(1)]

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources located in nonattainment areas, i.e., those areas where statutorily mandated health and welfare standards are being violated. In this respect, section 173 of the act requires that a new or modified source constructed in an area which exceeds the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3), for such category of source. The statute defines LAER as that rate of emission which reflects:

(A) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or

(B) The most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.

In no event can the emission rate exceed any applicable new source performance standard (section 171(3)).

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (part C). These provisions require that certain sources (referred to in section 169(1)) employ "best available control technology" (as defined in section 169(3)) for all pollutants regulated under the Act. Best available control technology (BACT) must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all events, State implementation plans (SIPs) approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of National Ambient Air Quality Standards designed to protect public health and welfare. For this purpose, SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

This regulation will be reviewed 4 years from the date of promulgation. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, and improvements in emissions control technology.

No economic impact assessment under Section 317 was prepared on this standard. Section 317(a) requires such an assessment only if "the notice of proposed rulemaking in connection with such standard . . . is published in the **Federal Register** after the date ninety days after August 7, 1977." This standard was proposed in the **Federal Register** on October 3, 1977, less than ninety days after August 7, 1977, and an assessment was therefore not required.

Dated: August 28, 1979.

Douglas M. Costle,

Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

It is proposed to amend Part 60 of Chapter I, Title 40 of the Code of Federal Regulations as follows:

1. By adding subpart GG as follows:

Subpart GG—Standards of Performance for Stationary Gas Turbines

Authority: Secs. 111 and 301(a) of the Clean Air Act, as amended, [42 U.S.C. 1857c-7, 1857g(a)], and additional authority as noted below.

Subpart GG—Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities: all stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel fired.

§ 60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Stationary gas turbine" means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) "Simple cycle gas turbine" means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) "Regenerative cycle gas turbine" means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) "Combined cycle gas turbine" means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) "Emergency gas turbine" means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) "Ice fog" means an atmospheric suspension of highly reflective ice crystals.

(g) "ISO standard day conditions" means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) "Efficiency" means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) "Peak load" means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) "Base load" means the load level at which a gas turbine is normally operated.

(k) "Fire-fighting turbine" means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) "Turbines employed in oil/gas production or oil/gas transportation" means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A "Metropolitan Statistical Area" or "MSA" as defined by the Department of Commerce.

(n) "Offshore platform gas turbines" means any stationary gas turbine located on a platform in an ocean.

(o) "Garrison facility" means any permanent military installation.

(p) "Gas turbine model" means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart, as specified in paragraphs (b), (c), and (d) of this section, shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), and (i) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

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where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in part (3) of this paragraph.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150 \left(\frac{14.4}{Y}\right) + F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in part (3) of this paragraph.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-Bound Nitrogen (percent by weight)	F (NO_x percent by volume)
$N \le 0.015$	0
$0.015 < N \le 0.1$	0.04(N)
$0.1 < N \le 0.25$	0.004 + 0.0067(N-0.1)
$N > 0.25$	0.005

where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by § 60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the **Federal Register.**

(b) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired except as provided in § 60.332(d) shall comply with the provisions of § 60.332(a)(1).

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of § 60.332(a)(2).

(d) Stationary gas turbines employed in oil/gas production or oil/gas transportation and not located in Metropolitan Statistical Areas; and offshore platform turbines shall comply with the provisions of § 60.332(a)(2).

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_x emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

§ 60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by § 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

§ 60.334 Monitoring of operations.

(a) The owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water injection to control NO_x emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within ±5.0 percent and shall be approved by the Administrator.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

(c) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with § 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under § 60.335(a).

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

(3) *Ice fog.* Each period during which an exemption provided in § 60.332(g) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(Sec. 114 of the Clean Air Act as amended [42 U.S.C. 1857c-9]).

§ 60.335 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.332 as follows:

(1) Reference Method 20 for the concentration of nitrogen oxides and oxygen. For affected facilities under this subpart, the span value shall be 300 parts per million of nitrogen oxides.

(i) The nitrogen oxides emission level measured by Reference Method 20 shall be adjusted to ISO standard day conditions by the following ambient condition correction factor:

$$NO_x = (NO_{x_{obs}}) \left(\frac{P_{ref}}{P_{obs}}\right)^{0.5} e^{19(H_{obs} - 0.00633)} \left(\frac{T_{AMB}}{288°K}\right)^{1.53}$$

where:

NO_x = emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.
$NO_{x_{obs}}$ = measured NO_x emissions at 15 percent oxygen, ppmv.
P_{ref} = reference combuster inlet absolute pressure at 101.3 kilopascals ambient pressure.
P_{obs} = measured combustor inlet absolute pressure at test ambient pressure.
H_{obs} = specific humidity of ambient air at test.
e = transcendental constant (2.718).
T_{AMB} = temperature of ambient air at test.

The adjusted NO_x emission level shall be used to determine compliance with § 60.332.

(ii) Manufacturers may develop custom ambient condition correction factors for each gas turbine model they manufacture in terms of combustor inlet pressure, ambient air pressure, ambient air humidity and ambient air temperature to adjust the nitrogen oxides emission level measured by the performance test as provided for in § 60.8 to ISO standard day conditions. These ambient condition correction factors shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by § 60.8. Notices of approval of custom ambient condition correction factors will be published in the **Federal Register.**

(iii) The water-to-fuel ratio necessary to comply with § 60.332 will be determined during the initial performance test by measuring NO_x emission using Reference Method 20 and the water-to-fuel ratio necessary to comply with § 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

(2) The analytical methods and procedures employed to determine the nitrogen content of the fuel being fired shall be approved by the Administrator and shall be accurate to within ±5 percent.

(b) The method for determining compliance with § 60.333, except as provided in § 60.8(b), shall be as follows:

(1) Reference Method 20 for the concentration of sulfur dioxide and oxygen or

(2) ASTM D2880-71 for the sulfur content of liquid fuels and ASTM D1072-70 for the sulfur content of gaseous fuels. These methods shall also be used to comply with § 60.334(b).

(c) Analysis for the purpose of determining the sulfur content and the nitrogen content of the fuel as required by § 60.334(b), this subpart, may be performed by the owner/operator, a service contractor retained by the owner/operator, the fuel vendor, or any other qualified agency provided that the analytical methods employed by these agencies comply with the applicable paragraphs of this section.

(Sec. 114 of the Clean Air Act as amended [42 U.S.C. 1857c–91]).

Appendix A—Reference Methods

2. Part 60 is amended by adding Reference Method 20 to Appendix A as follows:

* * * * *

Method 20—Determination of Nitrogen Oxides, Sulfur Dioxide, and Oxygen Emissions from Stationary Gas Turbines

1. Applicability and Principle

1.1 Applicability. This method is applicable for the determination of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and oxygen (O_2) emissions from stationary gas turbines. For the NO_x and O_2 determinations, this method includes: (1) measurement system design criteria, (2) analyzer performance specifications and performance test procedures; and (3) procedures for emission testing.

1.2 Principle. A gas sample is continuously extracted from the exhaust stream of a stationary gas turbine; a portion of the sample stream is conveyed to instrumental analyzers for determination of NO_x and O_2 content. During each NO_x and OO_2 determination, a separate measurement of SO_2 emissions is made, using Method 6, or it equivalent. The O_2 determination is used to adjust the NO_x and SO_2 concentrations to a reference condition.

2. Definitions

2.1 Measurement System. The total equipment required for the determination of a gas concentration or a gas emission rate. The system consists of the following major subsystems:

2.1.1 Sample Interface. That portion of a system that is used for one or more of the following: sample acquisition, sample transportation, sample conditioning, or protection of the analyzers from the effects of the stack effluent.

2.1.2 NO_x Analyzer. That portion of the system that senses NO_x and generates an output proportional to the gas concentration.

2.1.3 O_2 Analyzer. That portion of the system that senses O_2 and generates an output proportional to the gas concentration.

2.2 Span Value. The upper limit of a gas concentration measurement range that is specified for affected source categories in the applicable part of the regulations.

2.3 Calibration Gas. A known concentration of a gas in an appropriate diluent gas.

2.4 Calibration Error. The difference between the gas concentration indicated by the measurement system and the known concentration of the calibration gas.

2.5 Zero Drift. The difference in the measurement system output readings before and after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place and the input concentration at the time of the measurements was zero.

2.6 Calibration Drift. The difference in the measurement system output readings before and after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place and the input at the time of the measurements was a high-level value.

2.7 Residence Time. The elapsed time from the moment the gas sample enters the probe tip to the moment the same gas sample reaches the analyzer inlet.

2.8 Response Time. The amount of time required for the continuous monitoring system to display on the data output 95 percent of a step change in pollutant concentration.

2.9 Interference Response. The output response of the measurement system to a component in the sample gas, other than the gas component being measured.

3. Measurement System Performance Specifications

3.1 NO_2 to NO Converter. Greater than 90 percent conversion efficiency of NO_2 to NO.

3.2 Interference Response. Less than ± 2 percent of the span value.

3.3 Residence Time. No greater than 30 seconds.

3.4 Response Time. No greater than 3 minutes.

3.5 Zero Drift. Less than ± 2 percent of the span value.

3.6 Calibration Drift. Less than ± 2 percent of the span value.

4. Apparatus and Reagents

4.1 Measurement System. Use any measurement system for NO_x and O_2 that is expected to meet the specifications in this method. A schematic of an acceptable measurement system is shown in Figure 20–1. The essential components of the measurement system are described below:

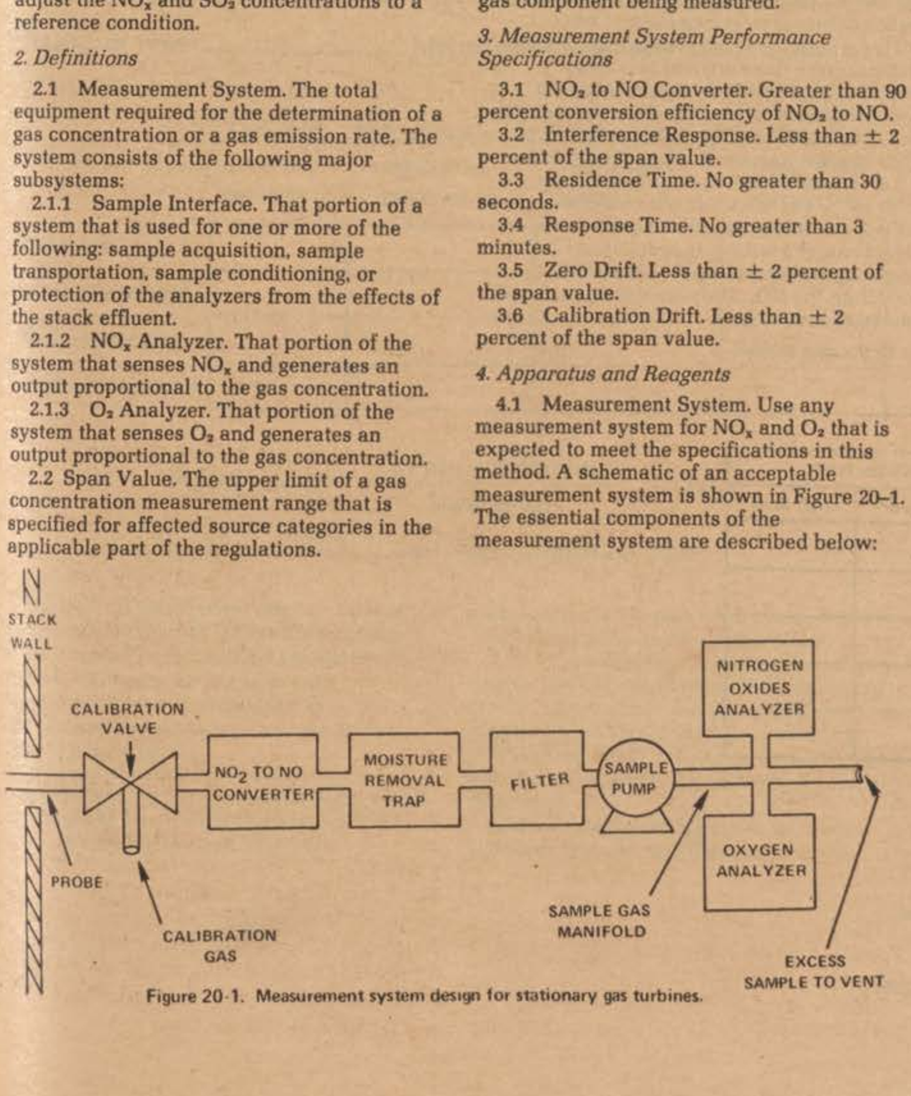

Figure 20-1. Measurement system design for stationary gas turbines.

4.1.1 Sample Probe. Heated stainless steel, or equivalent, open-ended, straight tube of sufficient length to traverse the sample points.

4.1.2 Sample Line. Heated (>95°C) stainless steel or Teflon tubing to transport the sample gas to the sample conditioners and analyzers.

4.1.3 Calibration Valve Assembly. A three-way valve assembly to direct the zero and calibration gases to the sample conditioners and to the analyzers. The calibration valve assembly shall be capable of blocking the sample gas flow and of introducing calibration gases to the measurement system when in the calibration mode.

4.1.4 NO_2 to NO Converter. That portion of the system that converts the nitrogen dioxide (NO_2) in the sample gas to nitrogen oxide (NO). Some analyzers are designed to measure NO_x as NO_2 on a wet basis and can be used without an NO_2 to NO converter or a moisture removal trap provided the sample line to the analyzer is heated (>95°C) to the inlet of the analyzer. In addition, an NO_2 to NO converter is not necessary if the NO_2 portion of the exhaust gas is less than 5 percent of the total NO_x concentration. As a guideline, an NO_2 to NO converter is not necessary if the gas turbine is operated at 90 percent or more of peak load capacity. A converter is necessary under lower load conditions.

4.1.5 Moisture Removal Trap. A refrigerator-type condenser designed to continuously remove condensate from the sample gas. The moisture removal trap is not necessary for analyzers that can measure NO_x concentrations on a wet basis; for these analyzers, (a) heat the sample line up to the inlet of the analyzers, (b) determine the moisture content using methods subject to the approval of the Administrator, and (c) correct the NO_x and O_2 concentrations to a dry basis

4.1.6 Particulate Filter. An in-stack or an out-of-stack glass fiber filter, of the type specified in EPA Reference Method 5; however, an out-of-stack filter is recommended when the stack gas temperature exceeds 250 to 300°C.

4.1.7 Sample Pump. A nonreactive leak-free sample pump to pull the sample gas through the system at a flow rate sufficient to minimize transport delay. The pump shall be made from stainless steel or coated with Teflon or equivalent.

4.1.8 Sample Gas Manifold. A sample gas manifold to divert portions of the sample gas stream to the analyzers. The manifold may be constructed of glass, Teflon, type 316 stainless steel, or equivalent.

4.1.9 Oxygen and Analyzer. An analyzer to determine the percent O_2 concentration of the sample gas stream.

4.1.10 Nitrogen Oxides Analyzer. An analyzer to determine the ppm NO_x concentration in the sample gas stream.

4.1.11 Data Output. A strip-chart recorder, analog computer, or digital recorder for recording measurement data.

4.2 Sulfur Dioxide Analysis. EPA Reference Method 6 apparatus and reagents.

4.3 NO_x Caliberation Gases. The calibration gases for the NO_x analyzer may be NO in N_2, NO_2 in air or N_2, or NO and NO_2

in N_2. For NO_x measurement analyzers that require oxidation of NO to NO_2, the calibration gases must be in the form of NO in N_2. Use four calibration gas mixtures as specified below:

4.3.1 High-level Gas. A gas concentration that is equivalent to 80 to 90 percent of the span value.

4.3.2 Mid-level Gas. A gas concentration that is equivalent to 45 to 55 percent of the span value.

4.3.3 Low-level Gas. A gas concentration that is equivalent to 20 to 30 percent of the span value.

4.3.4 Zero Gas. A gas concentration of less than 0.25 percent of the span value. Ambient air may be used for the NO_x zero gas.

4.4 O_2 Calibration Gases. Use ambient air at 20.9 percent as the high-level O_2 gas. Use a gas concentration that is equivalent to 11–14 percent O_2 for the mid-level gas. Use purified nitrogen for the zero gas.

4.5 NO_2/NO Gas Mixture. For determining the conversion efficiency of the NO_2 to NO converter, use a calibration gas mixture of NO_2 and NO in N_2. The mixture will be known concentrations of 40 to 60 ppm NO_2 and 90 to 110 ppm NO and certified by the gas manufacturer. This certification of gas concentration must include a brief description of the procedure followed in determining the concentrations.

5. Measurement System Performance Test Procedures

Perform the following procedures prior to measurement of emissions (Section 6) and only once for each test program, i.e., the series of all test runs for a given gas turbine engine.

5.1 Calibration Gas Checks. There are two alternatives for checking the concentrations of the calibration gases. (a) The first is to use calibration gases that are documented traceable to National Bureau of Standards Reference Materials. Use *Traceability Protocol for Establishing True Concentrations of Gases Used for Calibrations and Audits of Continuous Source Emission Monitors* (Protocol Number 1) that is available from the Environmental Monitoring and Support Laboratory, Quality Assurance Branch, Mail Drop 77, Environmental Protection Agency, Research Triangle Park, North Carolina 27711. Obtain a certification from the gas manufacturer that the protocol was followed. These calibration gases are not to be analyzed with the Reference Methods. (b) The second alternative is to use calibration gases not prepared according to the protocol. If this alternative is chosen, within 1 month prior to the emission test, analyze each of the calibration gas mixtures in triplicate using Reference Method 7 or the procedure outlined in Citation 8.1 for NO_x and use Reference Method 3 for O_2. Record the results on a data sheet (example is shown in Figure 20-2). For the low-level, mid-level, or high-level gas mixtures, each of the individual NO_x analytical results must be within 10 percent (or 10 ppm, whichever is greater) of the triplicate set average (O_2 test results must be within 0.5 percent O_2); otherwise, discard the entire set and repeat the triplicate analyses. If the average of the triplicate reference method test results is within 5 percent for NO_x gas or 0.5 percent O_2 for the O_2 gas of the calibration gas manufacturer's tag value, use the tag value; otherwise, conduct at least three additional reference method test analyses until the results of six individual NO_x runs (the three original plus three additional) agree within 10 percent (or 10 ppm, whichever is greater) of the average (O_2 test results must be within 0.5 percent O_2). Then use this average for the cylinder value.

5.2 Measurement System Preparation. Prior to the emission test, assemble the measurement system following the manufacturer's written instructions in preparing and operating the NO_2 to NO converter, the NO_x analyzer, the O_2 analyzer, and other components.

Date __________ (Must be within 1 month prior to the test period)

Reference method used ____________________

Sample run	Gas concentration, ppm		
	Low level[a]	Mid level[b]	High level[c]
1			
2			
3			
Average			
Maximum % deviation[d]			

[a] Average must be 20 to 30% of span value.

[b] Average must be 45 to 55% of span value.

[c] Average must be 80 to 90% of span value.

[d] Must be $\leq \pm$ 10% of applicable average or 10 ppm, whichever is greater.

Figure 20-2. Analysis of calibration gases.

5.3 Calibration Check. Conduct the calibration checks for both the NO_x and the O_2 analyzers as follows:

5.3.1 After the measurement system has been prepared for use (Section 5.2), introduce zero gases and the mid-level calibration gases; set the analyzer output responses to the appropriate levels. Then introduce each of the remainder of the calibration gases described in Sections 4.3 or 4.4, one at a time, to the measurement system. Record the responses on a form similar to Figure 20-3.

5.3.2 If the linear curve determined from the zero and mid-level calibration gas responses does not predict the actual response of the low-level (not applicable for the O_2 analyzer) and high-level gases within ±2 percent of the span value, the calibration shall be considered invalid. Take corrective measures on the measurement system before proceeding with the test.

5.4 Interference Response. Introduce the gaseous components listed in Table 20-1 into the measurement system separately, or as gas mixtures. Determine the total interference output response of the system to these components in concentration units; record the values on a form similar to Figure 20-4. If the sum of the interference responses of the test gases for either the NO_x or O_2 analyzers is greater than 2 percent of the applicable span value, take corrective measure on the measurement system.

Table 20-1.—*Interference Test Gas Concentration*

CO	500±50 ppm.
SO_2	200±20 ppm.
CO_2	10±1 percent.
O_2	20.9±1 percent.

Date of test ______-______-__

Analyzer type ______________ Serial No. ______________

Test gas type	Concentration, ppm	Analyzer output response	% of span

$$\% \text{ of span} = \frac{\text{Analyzer output response}}{\text{Instrument span}} \times 100$$

Figure 20-4. Interference response

Turbine type: ______________ Identification number ______________

Date: ______________ Test number ______________

Analyzer type: ______________ Identification number ______________

	Cylinder value, ppm or %	Initial analyzer response, ppm or %	Final analyzer responses, ppm or %	Difference: initial-final, ppm or %
Zero gas				
Low - level gas				
Mid - level gas				
High - level gas				

$$\text{Percent drift} = \frac{\text{Absolute difference}}{\text{Span value}} \times 100.$$

Figure 20-3. Zero and calibration data.

Conduct an interference response test of each analyzer prior to its initial use in the field. Thereafter, recheck the measurement system if changes are made in the instrumentation that could alter the interference response, e.g., changes in the type of gas detector.

In lieu of conducting the interference response test, instrument vendor data, which demonstrate that for the test gases of Table 20-1 the interference performance specification is not exceeded, are acceptable.

5.5 Residence and Response Time.

5.5.1 Calculate the residence time of the sample interface portion of the measurement system using volume and pump flow rate information. Alternatively, if the response time determined as defined in Section 5.5.2 is less than 30 seconds, the calculations are not necessary.

5.5.2 To determine response time, first introduce zero gas into the system at the calibration valve until all readings are stable; then, switch to monitor the stack effluent until a stable reading can be obtained. Record the upscale response time. Next, introduce high-level calibration gas into the system. Once the system has stabilized at the high-level concentration, switch to monitor the stack effluent and wait until a stable value is reached. Record the downscale response time. Repeat the procedure three times. A stable value is equivalent to a change of less than 1 percent of span value for 30 seconds or less than 5 percent of the measured average concentration for 2 minutes. Record the response time data on a form similar to Figure 20–5, the readings of the upscale or downscale reponse time, and report the greater time as the "response time" for the analyzer. Conduct a response time test prior to the initial field use of the measurement system, and repeat if changes are made in the measurement system.

Date of test ____________

Analyzer type ____________ S/N ____________

Span gas concentration ____________ ppm

Analyzer span setting ____________ ppm

Upscale
1 ____________ seconds
2 ____________ seconds
3 ____________ seconds

Average upscale response ____________ seconds

Downscale
1 ____________ seconds
2 ____________ seconds
3 ____________ seconds

Average downscale response ____________ seconds

System response time = slower average time = ____________ seconds.

Figure 20-5. Response time

5.6 NO_2 NO Conversion Efficiency. Introduce to the system, at the calibration valve assembly, the NO_2/NO gas mixture (Section 4.5). Record the response of the NO_x analyzer. If the instrument response indicates less than 90 percent NO_2 to NO conversion, make corrections to the measurement system and repeat the check. Alternatively, the NO_2 to NO converter check described in Title 40 Part 86: *Certification and Test Procedures for Heavy-Duty Engines for 1979 and Later Model Years* may be used. Other alternate procedures may be used with approval of the Administrator.

6. Emission Measurement Test Procedure

6.1 Preliminaries.

6.1.1 Selection of a Sampling Site. Select a sampling site as close as practical to the exhaust of the turbine. Turbine geometry, stack configuration, internal baffling, and point of introduction of dilution air will vary for different turbine designs. Thus, each of these factors must be given special consideration in order to obtain a representative sample. Whenever possible, the sampling site shall be located upstream of the point of introduction of dilution air into the duct. Sample ports may be located before or after the upturn elbow, in order to accommodate the configuration of the turning vanes and baffles and to permit a complete, unobstructed traverse of the stack. The sample ports shall not be located within 5 feet or 2 diameters (whichever is less) of the gas discharge to atmosphere. For supplementary-fired, combined-cycle plants, the sampling site shall be located between the gas turbine and the boiler. The diameter of the sample ports shall be sufficient to allow entry of the sample probe.

6.1.2 A preliminary O_2 traverse is made for the purpose of selecting low O_2 values. Conduct this test at the turbine condition that is the lowest percentage of peak load operation included in the program. Follow the procedure below or alternative procedures subject to the approval of the Administrator may be used:

6.1.2.1 Minimum Number of Points. Select a minimum number of points as follows: (1) eight, for stacks having cross-sectional areas less than 1.5 m^2 (16.1 ft^2); (2) one sample point for each 0.2 m^2 (2.2 ft^2 of areas, for stacks of 1.5 m^2 to 10.0 m^2 (16.1–107.6 ft^2) in cross-sectional area; and (3) one sample point for each 0.4 m^2 (4.4 ft^2) of area, for stacks greater than 10.0 m^2 (107.6 ft^2) in cross-sectional area. Note that for circular ducts, the number of sample points must be a multiple of 4, and for rectangular ducts, the number of points must be one of those listed in Table 20–2; therefore, round off the number of points (upward), when appropriate.

6.1.2.2 Cross-sectional Layout and Location of Traverse Points. After the number of traverse points for the preliminary O^2 sampling has been determined, use Method 1 to located the traverse points.

6.1.2.3 Preliminary O^2 Measurement. While the gas turbine is operating at the lowest percent of peak load, conduct a preliminary O^2 measurement as follows: Position the probe at the first traverse point and begin sampling. The minimum sampling time at each point shall be 1 minute plus the average system response time. Determine the average steady-state concentration of O^2 at each point and record the data on Figure 20–6.

6.1.2.4 Selection of Emission Test Sampling Points. Select the eight sampling points at which the lowest O^2 concentration were obtained. Use these same points for all the test runs at the different turbine load conditions. More than eight points may be used, if desired.

Table 20-2.—*Cross-sectional Layout for Rectangular Stacks*

No. of traverse points:	Matrix layout
9	3 x 3
12	4 x 3
16	4 x 4
20	5 x 4
25	5 x 5
30	6 x 5
36	6 x 6
42	7 x 6
49	7 x 7

Location: Date ______

Plant ______

City, State ______

Turbine identification:

Manufacturer ______

Model, serial number ______

Sample point	Oxygen concentration, ppm

Figure 20-6. Preliminary oxygen traverse.

6.2 NO_x and O_2 Measurement. This test is to be conducted at each of the specified load conditions. Three test runs at each load condition constitute a complete test.

6.2.1 At the beginning of each NO_x test run and, as applicable, during the run, record turbine data as indicated in Figure 20–7. Also, record the location and number of the traverse points on a diagram.

6.2.2 Position the probe at the first point determined in the preceding section and begin sampling. The minimum sampling time at each point shall be at least 1 minute plus the average system response time. Determine the average steady-state concentration of O_2 and NO_x at each point and record the data on Figure 20–8.

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TURBINE OPERATION RECORD

Test operator ________ Date ________

Turbine identification:

Type ________ Ultimate fuel

Serial No. ________ Analysis C ________

H ________

Location: O ________

Plant ________ N ________

City ________ S ________

Ambient temperature ________ Ash ________

H_2O ________

Ambient humidity ________

Trace Metals ________

Test time start ________ Na ________

Test time finish ________ Va ________

K ________

Fuel flow rate[a] ________ etc[b] ________

Water or steam ________ Operating load ________

Flow rate[a]

Ambient Pressure ________

[a]Describe measurement method, i.e., continuous flow meter, start finish volumes, etc.

[b]i.e., additional elements added for smoke suppression.

Figure 20-7. Stationary gas turbine data.

Turbine identification:

Manufacturer ________

Model, serial No. ________

Location:

Plant ________

City, State ________

Ambient temperature ________

Ambient pressure ________

Date ________

Test time - start ________

Test time - finish ________

Test operator name ________

O_2 instrument type ________

Serial No. ________

NO_x instrument type ________

Serial No. ________

Sample point	Time, min.	O_2^a, %	NO_x^a, ppm

[a]Average steady-state value from recorder or instrument readout.

Figure 20-8. Stationary gas turbine sample point record.

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6.2.3 After sampling the last point, conclude the test run by recording the final turbine operating parameters and by determining the zero and calibration drift, as follows:

Immediately following the test run at each load condition, or if adjustments are necessary for the measurement system during the tests, reintroduce the zero and mid-level calibration gases as described in Sections 4.3, and 4.4, one at a time, to the measurement system at the calibration valve assembly. (Make no adjustments to the measurement system until after the drift checks are made). Record the analyzers' responses on a form similar to Figure 20–3. If the drift values exceed the specified limits, the test run preceding the check is considered invalid and will be repeated following corrections to the measurement system. Alternatively, the test results may be accepted provided the measurement system is recalibrated and the calibration data that result in the highest corrected emission rate are used.

6.3 SO_2 Measurement. This test is conducted only at the 100 percent peak load condition. Determine SO_2 using Method 6, or equivalent, during the test. Select a minimum of six total points from those required for the NO_x measurements; use two points for each sample run. The sample time at each point shall be at least 10 minutes. Average the O_2 readings taken during the NO_x test runs at sample points corresponding to the SO_2 traverse points (see Section 6.2.2) and use this average O_2 concentration to correct the integrated SO_2 concentration obtained by Method 6 to 15 percent O_2 (see Equation 20–1).

If the applicable regulation allows fuel sampling and analysis for fuel sulfur content to demonstrate compliance with sulfur emission unit, emission sampling with Reference Method 6 is not required, provided the fuel sulfur content meets the limits of the regulation.

7. Emission Calculations

7.1 Correction to 15 Percent Oxygen. Using Equation 20–1, calculate the NO_x and SO_2 concentrations (adjusted to 15 percent O_2). The correction to 15 percent O_2 is sensitive to the accuracy of the O_2 measurement. At the level of analyzer drift specified in the method (±2 percent of full scale), the change in the O_2 concentration correction can exceed 10 percent when the O_2 content of the exhaust is above 16 percent O_2. Therefore O_2 analyzer stability and careful calibration are necessary.

$$C_{adj} = C_{meas} \times \frac{5.9}{20.9 - \%\, O_2} \qquad \text{(Equation 20-1)}$$

Where:

C_{adj}=Pollutant concentration adjusted to 15 percent O_2 (ppm)
C_{meas}=Pollutant concentration measured, dry basis (ppm)
5.9=20.9 percent O_2−15 percent O_2, the defined O_2 correction basis
Percent O_2=Percent O_2 measured, dry basis (%)

7.2 Calculate the average adjusted NO_x concentration by summing the point values and dividing by the number of sample points.

8. Citations

8.1 Curtis, F. A Method for Analyzing NO_x Cylinder Gases-Specific Ion Electrode Procedure, Monograph available from Emission Measurement Laboratory, ESED, Research Triangle Park, N.C. 27711, October 1978.

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